(3) Disconnection of a residential customer shall be postponed if the discontinuance of service would present an especial danger to the health of the customer or any permanent resident of the premises. An especial danger to health is indicated if one appears to be seriously impaired and may, because of mental or physical problems, be unable to manage one's own resources, carry out activities of daily living or protect oneself from neglect or hazardous situations without assistance from others. Indicators of an especial danger to health include but are not limited to: age, infirmity, or mental incapacitation; serious illness; physical disability, including blindness and limited mobility; and any other factual circumstances which indicate a severe or hazardous health situation. The utility may require written verification of the especial danger to health by a physician or a public health official, including the name of the person endangered, a statement that the person is a resident of the premises in question, the name, business address, and telephone number of the certifying party, the nature of the health danger and approximately how long the danger will continue. Initial verification by the verifying party may be by telephone if written verification is forwarded to the utility within five days.

Verification shall postpone disconnection for 30 days; however, the postponement may be extended for a renewal of the verification. In the event service is terminated within 14 days prior to verification of illness by or for a qualifying resident, service shall be restored to that residence if a proper verification is thereafter made in accordance with the foregoing provisions. The customer must pay the unpaid balance under the payment agreement within the first 30 days and keep the current account paid during the period that disconnection is postponed.

j. Without the written 12-day notice, for failure of a residential customer who has had service limited in accordance with subrule 20.4(23) to pay the full amount due for past service or to enter into a reasonable payment agreement, provided that:

(1) The minimum time period, as specified in the utility's tariff, for the service limiter to remain in place prior to initiation of the disconnection procedure has elapsed;

(2) The requirements of 20.4(15)*"i"*(1), relating to in-person, telephone or posted notice, have been satisfied;

(3) The requirements of 20.4(15)*"i"*(2), relating time and temperature restrictions on disconnection are satisfied, to the extent applicable; and

(4) The requirements of 20.4(15)*"i"*(3), relating to health restrictions on disconnection are satisfied, to the extent applicable.

20.4(16) *Insufficient reasons for denying service.* The following shall not constitute sufficient cause for refusal of service to a present or prospective customer:

a. Delinquency in payment for service by a previous occupant of the premises to be served.

b. Failure to pay for merchandise purchased from the utility.

c. Failure to pay for a different type or class of public utility service.

d. Failure to pay the bill of another customer as guarantor thereof.

e. Failure to pay a back bill rendered in accordance with 20.4(14)*"d."*

f. Failure to pay a bill rendered in accordance with 20.4(14)*"f."*

g. Failure of a residential customer to pay a deposit during the period November 1 through April 1 for the location at which the customer has been receiving service.

h. Rescinded IAB 4/15/92, effective 5/20/92.

20.4(17) *When disconnection prohibited.* No disconnection may take place from November 1 through April 1 for a resident who is a head of household and who has been certified to the public utility by the local community action agency as being eligible for either the low-income home energy assistance program or weatherization assistance program. No disconnection shall take place from April 1, 2001, through May 1, 2001, for eligible residents.

20.4(18) *Estimated demand.* Upon request of the customer and provided the customer's demand is estimated for billing purposes, the utility shall measure the demand during the customer's normal operation and use the measured demand for billing.

20.4(19) *Servicing utilization control equipment.* Each utility shall service and maintain any equipment it uses on customer's premises and shall correctly set and keep in proper adjustment any thermostats, clocks, relays, time switches or other devices which control the customer's service in accordance with the provisions in the utility's rate schedules.

20.4(20) *Customer complaints.* Complaints concerning the charges, practices, facilities or service of the utility shall be investigated promptly and thoroughly. The utility shall keep such records of customer complaints as will enable it to review and analyze its procedures and actions.

a. Each utility shall provide in its filed tariff a concise, fully informative procedure for the resolution of customer complaints.

b. The utility shall take reasonable steps to ensure that customers unable to travel shall not be denied the right to be heard.

c. The final step in a complaint hearing and review procedure shall be a filing for board resolution of the issues.

20.4(21) *Temporary service.* When the utility renders temporary service to a customer it may require that the customer bear all of the cost of installing and removing the service facilities in excess of any salvage realized.

20.4(22) *Change in type of service.* If a change in the type of service, such as from 25- to 60-cycle or from direct or alternating current, or a change in voltage to a customer's substation, is effected at the insistence of the utility and not solely by reason of increase in the customer's load or change in the character thereof, the utility shall share equitably in the cost of changing the equipment of the customer affected as determined by the board in the absence of agreement between utility and customer. In general, the customer should be protected against or reimbursed for the following losses and expenses to an appropriate degree:

a. Loss of value in electrical power utilization equipment.

b. Cost of changes in wiring, and

c. Cost of removing old and installing new utilization equipment.

20.4(23) *Limitation of service.* The utility shall have the option of adopting a policy for limiting the service of a residential customer for nonpayment of a bill or deposit, or for noncompliance with the terms of a payment agreement, as a measure to be taken prior to disconnection of the customer. Electric-heating residential customers shall not have limited service between November 1 and April 1. For purposes of this rule, "electric-heating" shall mean heating by means of a fixed-installation electric appliance which serves as the primary heat source.

A service limitation policy, if adopted by the utility, shall be set forth in the utility's tariff and shall specify some minimum time period for the service limiter to remain in place prior to the initiation of the disconnection procedure set forth in 20.4(15)*"j."* A service limitation policy, if adopted by the utility, shall be applied uniformly to all of the utility's residential customers, as specified above, to the extent that adaptation of service limiters to customer meters is feasible, and to the extent that customer meters are readily accessible to those installing the service limiters and to the customers. Any other exceptions to uniform application of this policy must be on the basis of rational, specific criteria set forth in the utility's tariff receiving prior approval by the board.

Notice of a pending service limitation shall be rendered, and electric service limited, as set forth in the tariff.

Upon installing a service limiter, the utility shall post the premises with a notice informing the occupant of the installation of the service limiter, its purpose, how it operates, and how it can be reset by the occupant.

The notice of pending service limitation required by these rules shall satisfy the requirements of subrule 20.4(15), substituting "service limitation" for "disconnection" or "refusal or disconnection of service" throughout the rule.

Service may be limited for nonpayment of bill or deposit, except as restricted by subrule 20.4(16), relating to insufficient reasons for denying service, provided that the utility has satisfied the requirements of 20.4(15)*"h,"* excluding the portion of subparagraph (4) "special circumstances" relating to same-day reconnection, and substituting "service limitation" for "disconnection" (and all other forms of that term) throughout that subrule. An installed service limiter shall be removed no later than the next working day after the residential customer has paid the delinquent bill or deposit in full or has entered into a reasonable payment agreement with the utility.

Service may be limited without the written 12-day notice for failure of the customer to comply with the terms of a payment agreement, provided that the requirements of 20.4(15)*"i"* have been satisfied, excluding the portion of subparagraph (2) relating to same-day reconnection, and substituting "service limitation" for "disconnection" (and all other forms of that term) throughout that subrule.

These rules are intended to implement Iowa Code sections 476.6, 476.8, 476.20 and 476.54.

199—20.5(476) Engineering practice.

20.5(1) *Requirement for good engineering practice.* The electric plant of the utility shall be constructed, installed, maintained and operated in accordance with accepted good engineering practice in the electric industry to assure, as far as reasonably possible, continuity of service, uniformity in the quality of service furnished, and the safety of persons and property.

20.5(2) *Standards incorporated by reference.* The utility shall use the applicable provisions in the publications listed below as standards of accepted good practice unless otherwise ordered by the board.

a. Iowa Electrical Safety Code, as defined in IAC [199], Chapter 25.

b. National Electrical Code, ANSI/NFPA 70-2002.

c. American National Standard Requirements for Instrument Transformers, ANSI/IEEE C57.13.1-1981 (R1999); and C57.13.3-1983 (R1991).

d. American National Standard Requirements for Electrical Analog Indicating Instruments, ANSI C39.1-1981 (R1992).

e. Rescinded IAB 11/19/97, effective 12/24/97.

f. American National Standard Voltage Ratings for Electric Power Systems and Equipment (60Hz), ANSI C84.1-1995.

g. Grounding of Industrial and Commercial Power Systems, IEEE 142-1991.

h. IEEE Standard 1159-1995, IEEE Recommended Practice for Monitoring Electric Power Quality or any successor standard.

i. IEEE Standard 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems or its successor standard.

20.5(3) *Adequacy of supply and reliability of service.* The generating capacity of the utility's plant, supplemented by the electric power regularly available from other sources, must be sufficiently large to meet all normal demands for service and provide a reasonable reserve for emergencies.

In appraising adequacy of supply the board will segregate electric utilities into two classes viz., those having high capacity transmission interconnections with other electrical utilities and those which lack such interconnection and are therefore completely dependent upon the firm generating capacity of the utility's own generating facilities.

a. In the case of utilities having interconnecting ties with other utilities, the board will, upon appraising adequacy of supply, take appropriate notice of the utility's recent past record, as of the date of appraisal, of any widespread service interruptions and any capacity shortages along with the consideration of the supply regularly available from other sources, the normal demands, and the required reserve for emergencies.

b. In the case of noninterconnected utilities the board will give attention to the maximum total coincident customer demand which could be satisfied without the use of the single element of plant equipment, the disability of which would produce the greatest reduction in total net plant productive capacity and also give attention to the normal demands for service and to the reasonable reserve for emergencies.

20.5(4) *Electric transmission and distribution facilities.* Rescinded IAB 11/13/02, effective 12/18/02.

20.5(5) *Inspection of electric plant.* Each utility shall adopt a written program for inspection of its electric plant in order to determine the necessity for replacement and repair in compliance with board rule 199—25.3(476,478).

This rule is intended to implement Iowa Code section 476.8 and 478.18.

199—20.6(476) Metering.

20.6(1) *Inspection and testing program.* Each utility shall adopt a written program for the inspection and testing of its meters to determine the necessity for adjustment, replacement or repair. The frequency of inspection and methods of testing shall be based on the utility's experience, manufacturer's recommendations, and accepted good practice. The publications listed in 20.6(3) are representative of accepted good practice. Each utility shall maintain inspecting and testing records for each meter and associated device until three years after its retirement.

20.6(2) *Program content.* The written program shall, at minimum, address the following subject areas:

a. Classification of meters by capacity, type, and any other factor considered pertinent.

b. Checking of new meters for acceptable accuracy before being placed in service.

c. Testing of in-service meters, including any associated instruments or corrective devices, for accuracy, adjustments or repairs. This may be accomplished by periodic tests at specified intervals or on the basis of a statistical sampling plan, but shall include meters removed from service for any reason.

d. Periodic calibration or testing of devices or instruments used by the utility to test meters.

e. The limits of meter accuracy considered acceptable by the utility.

f. The nature of meter and meter test records which will be maintained by the utility.

20.6(3) *Accepted good practice.* The following publications are considered to be representative of accepted good practice in matters of metering and meter testing:

a. American National Standard Code for Electricity Metering, ANSI C12.1-2001.

b. American National Standard for Solid-State Electricity Meters, ANSI C12.16-1991.

c. American National Standard for Cartridge-type Solid-State Pulse Recorders for Electricity Metering, ANSI C12.17-1991.

20.6(4) *Meter adjustment.* All meters and associated metering devices shall, when tested, be adjusted as closely as practicable to the condition of zero error.

20.6(5) *Request tests.* Upon request by a customer, a utility shall test the meter servicing that customer. A test need not be made more frequently than once in 18 months.

A written report of the test results shall be mailed to the customer within ten days of the completed test and a record of each test shall be kept on file at the utility's office. The utility shall give the customer or a representative of the customer the opportunity to be present while the test is conducted.

If the test finds the meter is accurate within the limits accepted by the utility in its meter inspection and testing program, the utility may charge the customer $25 or the cost of conducting the test, whichever is less. The customer shall be advised of any potential charge before the meter is removed for testing.

20.6(6) *Referee tests.* Upon written request by a customer or utility, the board will conduct a referee test of a meter. A test need not be made more frequently than once in 18 months. The customer request shall be accompanied by a $30 deposit in the form of a check or money order made payable to the utility.

Within five days of receipt of the written request and payment, the board shall forward the deposit to the utility and notify the utility of the requirement for a test. The utility shall, within 30 days after notification of the request, schedule the date, time and place of the test with the board and customer. The meter shall not be removed or adjusted before the test. The utility shall furnish all testing equipment and facilities for the test. If the tested meter is found to be more than 2 percent fast or 2 percent slow, the deposit will be returned to the party requesting the test and billing adjustments shall be made as required in 20.4(14). The board shall issue its report within 15 days after the test is conducted, with a copy to the customer and the utility.

20.6(7) *Condition of meter.* No meter that is known to be mechanically or electrically defective, or to have incorrect constants, or that has not been tested and adjusted if necessary in accordance with these rules shall be installed or continued in service. The capacity of the meter and the index mechanism shall be consistent with the electricity requirements of the customer.

199—20.7(476) Standards of quality of service.

20.7(1) Standard frequency. The standard frequency for alternating current distribution systems shall be 60 cycles per second. The frequency shall be maintained within limits which will permit the satisfactory operation of customer's clocks connected to the system.

20.7(2) Voltage limits retail. Each utility supplying electric service to ultimate customers shall provide service voltages in conformance with the standard at 20.5(2)*"f."*

20.7(3) Voltage balance. Where three-phase service is provided the utility shall exercise reasonable care to assure that the phase voltages are in balance. In no case shall the ratio of maximum voltage deviation from average to average voltage exceed .02.

20.7(4) Voltage limits, service for resale. The nominal voltage shall be as mutually agreed upon by the parties concerned. The allowable variation shall not exceed 7.5 percent above or below the agreed-upon nominal voltage without the express approval of the board.

20.7(5) Exceptions to voltage requirements. Voltage outside the limits specified will not be considered a violation when the variations:

a. Arise from the action of the elements.

b. Are infrequent fluctuations not exceeding five minutes, duration.

c. Arise from service interruptions.

d. Arise from temporary separation of parts of the system from the main system.

e. Are from causes beyond the control of the utility.

f. Do not exceed 10 percent above or below the standard nominal voltage, and service is at a distribution line or transmission line voltage with the retail customer providing voltage regulators.

20.7(6) Voltage surveys and records. Voltage measurements shall be made at the customer's entrance terminals. For single-phase service the measurement shall be made between the grounded conductor and the ungrounded conductors. For three-phase service the measurement shall be made between the phase wires.

20.7(7) Each utility shall make a sufficient number of voltage measurements, using recording voltmeters, in order to determine if voltages are in compliance with the requirements as stated in 20.7(2), 20.7(3), 20.7(4). All voltmeter records obtained under 20.7(7) shall be retained by the utility for at least two years and shall be available for inspection by the board's representatives. Notations on each chart shall indicate the following:

a. The location where the voltage was taken.

b. The time and date of the test.

c. The results of the comparison with a working standard indicating voltmeter.

20.7(8) Equipment for voltage measurements.

a. *Secondary standard indicating voltmeter.* Each utility shall have available at least one indicating voltmeter maintained with error no greater than 0.25 percent of full scale.

b. *Working standard indicating voltmeters.* Each utility shall have at least two indicating voltmeters maintained so as to have as-left errors of no greater than 1 percent of full scale.

c. *Recording voltmeters.* Each utility must have readily available at least two portable recording voltmeters with a rated accuracy of 1 percent of full scale.

20.7(9) Rescinded IAB 12/11/91, effective 1/15/92.

20.7(10) Extreme care must be exercised in the handling of standards and instruments to assure that their accuracy is not disturbed. Each standard shall be accompanied at all times by a certificate or calibration card, duly signed and dated, on which are recorded the corrections required to compensate for errors found at the customary test points at the time of the last previous test.

20.7(11) Planned interruptions shall be made at a time that will not cause unreasonable inconvenience to customers, and interruptions planned for longer than one hour shall be preceded by adequate notice to those who will be affected.

20.7(12) Power quality monitoring. Each utility shall investigate power quality complaints from its customers and determine if the cause of the problem is on the utility's systems. In addressing these problems, each utility shall implement to the extent reasonably practical the practices outlined in the standard given at 20.5(2)*"h."*

20.7(13) Harmonics. A harmonic is a sinusoidal component of the 60 cycles per second fundamental wave having a frequency that is an integral multiple of the fundamental frequency. When excessive harmonics problems arise, each electric utility shall investigate and take actions to rectify the problem. In addressing harmonics problems, the utility and the customer shall implement to the extent practicable and in conformance with prudent operation the practices outlined in the standard at 20.5(2)*"i."*

This rule is intended to implement Iowa Code sections 476.2 and 476.8.

199—20.8(476) Safety.

20.8(1) *Protective measures.* Each utility shall exercise reasonable care to reduce those hazards inherent in connection with its utility service and to which its employees, its customers, and the general public may be subjected and shall adopt and execute a safety program designed to protect the public and fitted to the size and type of its operations.

20.8(2) *Accident investigation and prevention.* The utility shall give reasonable assistance to the board in the investigation of the cause of accidents and in the determination of suitable means of preventing accidents.

20.8(3) *Reportable accidents.* Each utility shall maintain a summary of all reportable accidents, as defined in 199—25.5(476,478), arising from its operations.

20.8(4) *Grounding of secondary distribution system.* Unless otherwise specified by the board, each utility shall comply with, and shall encourage its customers to comply with, the applicable provisions of the acceptable standards listed in 20.5(2) for the grounding of secondary circuits and equipment.

Ground connections should be tested for resistance at the time of installation. The utility shall keep a record of all ground resistance measurements.

The utility shall establish a program of inspection so that all artificial grounds installed by it shall be inspected within reasonable periods of time.

199—20.9(476) Electric energy sliding scale or automatic adjustment. A rate-regulated utility's sliding scale or automatic adjustment of the unit charge for electric energy shall be an energy clause.

20.9(1) *Applicability.* A rate-regulated utility's sliding scale or automatic adjustment of electric utility energy rates shall recover from consumers only those costs which:

Are incurred in supplying energy;

Are beyond direct control of management;

Are subject to sudden important change in level;

Are an important factor in determining the total cost to serve; and

Are readily, precisely, and continuously segregated in the accounts of the utility.

20.9(2) *Energy clause for rate-regulated utility.* Prior to each billing cycle, a rate-regulated utility shall determine and file for board approval the adjustment amount to be charged for each energy unit consumed under rates set by the board. The filing shall include all journal entries, invoices (except invoices for fuel, freight, and transportation), worksheets, and detailed supporting data used to determine the amount of the adjustment. The estimated amount of fossil fuel should be detailed to reflect the amount of fuel, transportation, and other costs.

The journal entries should reflect the following breakdown for each type of fuel: actual cost of fuel, transportation, and other costs. Items identified as other costs should be described and their inclusion as fuel costs should be justified. The utility shall also file detailed supporting data:

1. To show the actual amount of sales of energy by month for which an adjustment was utilized, and

2. To support the energy cost adjustment balance utilized in the monthly energy adjustment clause filings.

a. The energy adjustment shall provide for change of the price per kilowatt hour consumed under rates set by the board based upon the formulas provided below. The calculation shall be:

$$E_0 = \frac{EC_0 + EC_1}{EQ_0 + EQ_1} + \frac{A_1}{EJ_0 + EJ_1} - B$$

E_0 is the energy adjustment charge to be used in the next customer billing cycle rounded on a consistent basis to either the nearest 0.01¢/kWh or 0.001¢/kWh. For deliveries at voltages higher than secondary line voltages, appropriate factors should be applied to the adjustment charge to recognize the lower losses associated with these deliveries.

EC_0 is the estimated expense for energy in the month during which E_0 will be used.

EC_1 is the estimated expense for energy in the month prior to the month of EC_0.

EQ_0 is the estimated electric energy to be consumed or delivered and entered in accounts 440, 442, 444-7, excluding energy from distinct interchange deliveries entered into account 447 and including intrautility energy service as included in accounts 448 and 929 of the Uniform System of Accounts during the month in which E_0 will be used.

EQ_1 is the estimated electric energy to be consumed or delivered and entered in accounts 440, 442, 444-7, excluding energy from distinct interchange deliveries entered in account 447 and including intrautility energy service as included in accounts 448 and 929 of the Uniform System of Accounts during the month prior to EQ_0.

EJ_0 is the estimated electric energy to be consumed under rates set by the board in the month during which the energy adjustment charge (E_0) will be used in bill calculations.

EJ_1 is the estimated electric energy to be consumed under rates set by the board in the month prior to the month of EJ_0.

A_1 is the beginning of the month energy cost adjustment account balance for the month of estimated consumption EJ_1. This would be the most recent month's balance available from actual accounting data.

B is the amount of the electric energy cost included in the base rates of a utility's rate schedules.

b. The estimated energy cost ($EC_0 + EC_1$) shall be the estimated cost associated with EQ_0 and EQ_1 determined as the cost of:

(1) Fossil and nuclear fuel consumed in the utility's own plants and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants. Fossil fuel shall include natural gas used for electric generation and the cost of fossil fuel transferred from account 151 to account 501 or 547 of the Uniform System of Accounts for Electric Utilities. Nuclear fuel shall be that shown in account 518 of the Uniform System of Accounts except that if account 518 contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from the account. (Paragraph C of account 518 includes the cost of other fuels used for ancillary steam facilities.)

(2) The cost of steam purchased, or transferred from another department of the utility or from others under a joint facility operating agreement, for use in prime movers producing electric energy (accounts 503 and 521).

(3) A deduction shall be made of the expenses of producing steam chargeable to others, to other utility departments under a joint operating agreement, or to other electric accounts outside the steam generation group of accounts (accounts 504 and 522).

(4) The cost of water used for hydraulic power generation. Water cost shall be limited to items of account 536 of the Uniform System of Accounts. For pumped storage projects the energy cost of pumping is included. Pumping energy cost shall be determined from the applicable costs of subparagraphs of paragraph 20.9(2)*"b."*

(5) The energy costs paid for energy purchased under arrangements or contracts for firm power, operational control energy, outage energy, participation power, peaking power, and economy energy, as entered into account 555 of the Uniform System of Accounts, less the energy revenues to be recovered from corresponding sales, as entered in account 447 of the Uniform System of Accounts.

(6) Purchases from AEP facilities under rule 199—15.11(476).

(7) The weighted average costs of inventoried allowances used in generating electricity.

(8) The gains and losses from allowance sales occurring during the month.

(9) Eligible costs or credits associated with the utility's annual reconciliation of its alternate energy purchase program under 199—paragraph 15.17(4)*"b."*

c. The energy cost adjustment account balance (A) shall be the cumulative balance of any excess or deficiency which arises out of the difference between board recognized energy cost recovery and the amount recovered through application of energy charges to consumption under rates set by the board. Each monthly entry (D) into the energy cost adjustment account shall be the dollar amount determined from solution of the following equation (with proper adjustment for those deliveries at high voltage which for billing purposes recognized the lower losses associated with the high voltage deliveries).

$$D = \left[C_2 \times \frac{J_2}{Q_2} \right] - \left[J_2 \times (E_2 + B) \right]$$

C_2 is the actual expense for energy, calculated as set forth in 20.9(2)*"b,"* in the month prior to EJ_1 of 20.9(2)*"a."*

J_2 is the actual energy consumed in the prior month under rates set by the board and recorded in accounts 440, 442 and 444-6 of the Uniform System of Accounts.

Q_2 is the actual total energy consumed or delivered in the prior month and recorded in accounts 440, 442, 444-7, excluding energy from distinct interchange deliveries entered in account 447, and including intrautility energy service as included in accounts 448 and 929 of the Uniform System of Accounts.

E_2 is the energy adjustment charge used for billing in the prior month.

B is the amount of the electric energy cost included in the base rates of a utility's rate schedules.

d. Reserve account for nuclear generation. A rate-regulated utility owning nuclear generation or purchasing energy under a participation power agreement on nuclear generation may establish a reserve account. The reserve account will spread the higher cost of energy used to replace that normally received from nuclear sources. A surcharge would be added to each kilowatt hour from the nuclear source. The surcharges collected are credited to the reserve account. During an outage or reduced level of operation, replacement energy cost would be offset through debit to the reserve account. The debit would be based upon the cost differential between replacement energy cost and the average cost (including the surcharge) of energy from the nuclear capacity. A reserve account shall have credit and debit limitations equal in dollar amounts to the total cost differential for replacement energy during a normal refueling outage.

e. A rate-regulated utility desiring to collect expensed allowance costs and the gains and losses from allowance transactions through the energy adjustment must file with the board monthly reports including:

(1) The number and weighted average unit cost of allowances used during the month to offset sulfur dioxide emissions from the utility's affected units;

(2) The number and unit price of allowances purchased during the month;
(3) The number and unit price of allowances sold during the month;
(4) The weighted average unit cost of allowances remaining in inventory;
(5) The dollar amount of any gain from an allowance sale occurring during the month;
(6) The dollar amount of any loss from an allowance sale occurring during the month; and
(7) Documentation of any gain or loss from an allowance sale occurring during the month.

f. A rate-regulated utility which proposes a new sliding scale or automatic adjustment clause of electric utility energy rates shall conform such clause with the rules.

20.9(3) *Optional energy clause for a rate-regulated utility which does not own generation.* A rate-regulated utility which does not own generation may adopt the energy adjustment clause of this subrule in lieu of that set forth in subrule 20.9(2). Prior to each billing cycle it shall determine and file for board approval the adjustment amount to be charged for each energy unit consumed under rates set by the board. The filing shall include all journal entries, invoices (except invoices for fuel, freight, and transportation), worksheets, and detailed supporting data used to determine the amount of the adjustment. The estimated amount of fossil fuel should be detailed to reflect the amount of fuel, transportation, and other costs.

The journal entries should reflect the following breakdown for each type of fuel: actual cost of fuel, transportation, and other costs. Items identified as other costs should be described and their inclusion as fuel costs should be justified. The utility shall also file detailed supporting data:

1. To show the actual amount of sales of energy by month for which an adjustment was utilized, and

2. To support the energy cost adjustment balance utilized in the monthly energy adjustment clause filings.

a. The energy adjustment charge shall provide for change of the price per kilowatt-hour consumed to equal the average cost per kilowatt hour delivered by the utility's system. The calculation shall be:

$$E_0 = \frac{C_2 + C_3 + C_4}{Q_2 + Q_3 + Q_4} - B$$

E_0 is the energy adjustment charge to be used in the next customer billing cycle rounded on a consistent basis to either the nearest 0.01¢/kWh or 0.001¢/kWh. For deliveries at voltages higher than secondary line voltages, appropriate factors should be applied to the adjustment charge to recognize the lower losses associated with these deliveries.

C_2, C_3 and C_4 are the charges by the wholesale suppliers as recorded in account 555 offset by energy revenues from distinct interchange deliveries entered in account 447 of the Uniform System of Accounts for the first three of the four months prior to the month in which E_0 will be used.

Q_2, Q_3 and Q_4 are the total electric energy delivered by the utility system, excluding energy from distinct interchange deliveries entered in account 447 during each of the months in which the expenses C_2, C_3 and C_4 were incurred.

B is the amount of the electric energy cost included in the base rates of a utility's rate schedules.

b. A utility purchasing its total electric energy requirements may establish an energy cost adjustment account for which the cumulative balance is the excess or deficiency arising from the difference between commission-recognized energy cost recovery and the amount recovered through application of energy charges on jurisdictional consumption.

For a utility electing to use an energy cost adjustment account the calculation shall be:

$$E_0 = \frac{C_2 + C_3 + C_4}{Q_2 + Q_3 + Q_4} + \frac{A_2}{J_2 + J_3 + J_4} - B$$

E_0 is the energy adjustment charge to be used in the next customer billing cycle rounded on a consistent basis to either the nearest 0.01¢/kWh or 0.001¢/kWh. For deliveries at voltages higher than secondary line voltages, appropriate factors should be applied to the adjustment charge to recognize the lower losses associated with these deliveries.

C_2, C_3 and C_4 are the charges by the wholesale suppliers as recorded in account 555 offset by energy revenues from distinct interchange deliveries entered in account 447 of the Uniform System of Accounts for the first three of the four months prior to the month in which E_0 will be used.

Q_2, Q_3 and Q_4 are the total electric energy delivered by the utility system, excluding energy from distinct interchange deliveries entered in account 447 during each of the months in which the expenses C_2, C_3 and C_4 were incurred.

A_2 is the end of the month energy cost adjustment account balance for the month of consumption J_2. This would be the most recent month's balance available from actual accounting data.

J_2, J_3 and J_4 are electric energy consumed under rates set by the board in the months corresponding to C_2, C_3 and C_4.

B is the amount of the electric energy cost included in the base rates of a utility's rate schedules.

c. The end of the month energy cost adjustment account balance (A) shall be the cumulative balance of any excess or deficiency which arises out of the difference between board recognized energy cost recovery and the amount recovered through application of energy charges to consumption under rates set by the board.

Each monthly entry (D) into the energy cost adjustment account shall be the dollar amount determined from solution of the following equation (with proper adjustment for those deliveries at high voltage which for billing purposes recognized the lower losses associated with the high voltage deliveries).

$$D = \left[C_2 \times \frac{J_2}{Q_2} \right] - \left[J_2 \times (E_2 + B) \right]$$

C_2 is the prior month charges by the wholesale suppliers as recorded in account 555 of the Uniform System of Accounts offset by energy revenues from distinct interchange deliveries entered in account 447.

J_2 is the electric energy consumed under jurisdictional rates in the prior month.

Q_2 is the electric energy delivered by the utility system, excluding energy from distinct interchange deliveries entered in account 447 in the prior month.

E_2 is the energy adjustment charge used for billing in the prior month.

B is the amount of the electric energy cost included in the base rates of a utility's rate schedules.

d. A utility with special conditions may petition the board for a waiver which would recognize its unique circumstances.

e. A utility which does not own generation and proposes a new sliding scale or automatic adjustment clause of electric utility rates shall conform such clause with the rules.

20.9(4) *Annual review of energy clause.* On or before each May 1, the board will notify each utility as to the two months of the previous calendar year for which fuel, freight, and transportation invoices will be required. Two copies of these invoices shall be filed with the board no later than the subsequent November 1.

This rule is intended to implement Iowa Code section 476.6(11).

199—20.10(476) Ratemaking standards.

20.10(1) *Coverage.* Standards for ratemaking shall apply to all rate-regulated utilities in the state of Iowa. The board may, by rule or by order in specific cases, exempt a utility or class of utilities from any or all ratemaking standards. The standards are recommended to all service-regulated utilities in this jurisdiction.

20.10(2) *Cost of service.* Rates charged by an electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reasonably reflect the costs of providing electric service to the class. The methods used to determine class costs of service shall to the maximum extent practical permit identification of differences in cost-incurrence, for each class of electric consumers, attributable to daily and seasonal time of use of service, and permit identification of differences in cost-incurrence attributable to differences in demand, energy, and customer components of cost.

The design of rates should reasonably approximate a pricing methodology for any individual utility that would reflect the price system that would exist in a competitive market environment. For purposes of determining revenue requirements among customer classes, embedded costs shall be preferred. For purposes of determining rate designs within customer classes, long-run marginal cost approaches are preferred although embedded cost approaches may be considered reasonable.

Nothing in this rule shall authorize or require the recovery by an electric utility of revenues in excess of, or less than, the amount of revenues otherwise determined to be lawful by the board.

Guidelines for use in evaluating the acceptability of methods of class cost of service estimation include, but are not limited to, the following:

a. All usage of customer, demand, and energy components of service shall be considered new usage.

b. Customer classes shall be established on the primary basis of reasonably similar usage patterns within classes, even if this requires disaggregation or recombination of traditional customer classes.

c. Generating capacity estimates or allocations among and within classes shall recognize that utility systems are designed to serve both peak and off-peak demand, and shall attribute costs based upon both peak period demand and the contribution of off-peak period demand in determining generation mix. Generating capacity estimates and allocations among and within classes shall be based on load data for each class as described in 199—subrule 35.9(2).

d. Transmission and distribution capacity estimates or allocations among and within classes shall be demand-related based upon system usage patterns, and the load imposed by a class on the transmission or distribution capacity in question.

e. Customer cost component estimates or allocations shall include only costs of the distribution system from and including transformers, meters and associated customer service expenses.

f. Methods of cost estimates or allocations among customer classes shall recognize the differences in voltage levels and other service characteristics, and line losses among customer classes.

g. Methods of class cost of service determination which are consistent with zero customer, demand, or energy component costs or major categories of these, such as generation, transmission or distribution, shall be considered unacceptable methods.

h. Long-run marginal cost methods of class cost of service determination shall clearly reflect changes in total costs to the utility with respect to changes in the outputs of customer, demand, or energy components of electric services.

i. The use of an inverse elasticity approach to adjust long-run marginal cost-based rates to the revenue requirement shall be unacceptable. Other approaches will be considered on a case-by-case basis.

20.10(3) *Declining block rates.* The energy-related cost component of a rate, or the amount attributable to the energy-related cost component of a rate, charged by an electric utility for providing electric service during any period to any class of electric consumers, shall not decrease as kilowatt-hour consumption by such class increases during the period except to the extent that the utility demonstrates that the energy costs of providing electric service to such class decrease as consumption increases during the period.

20.10(4) *Time-of-day rates.* The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the cost of providing electric service to that class of electric consumers at different times of the day unless such rates are not cost-effective with respect to the class. These rates are cost-effective with respect to a class if the long-run benefits of the rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering costs and other costs associated with the use of the rates. Cost-based time-of-day rates shall be offered on an optional basis to electric consumers who do not otherwise qualify for the rates if consumers agree to pay the additional metering costs and other costs associated with the use of the rates.

20.10(5) *Seasonal rates.* The rates charged by an electric utility for providing electric service to each class of electric consumers may be on a seasonal basis which reflects the costs of providing service to the class of consumers at different seasons of the year to the extent that costs vary seasonally for the utility, if the board determines that seasonal rates are appropriate in an individual case.

20.10(6) *Interruptible rates.* Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which the consumer is a member.

20.10(7) *Load management techniques.* Rescinded IAB 11/12/03, effective 12/17/03.

20.10(8) *Other energy conservation strategies.* Rescinded IAB 11/12/03, effective 12/17/03.

20.10(9) *Pilot projects.* Rescinded IAB 11/12/03, effective 12/17/03.

199—20.11(476) Customer notification of peaks in electric energy demand. Each electric utility shall inform its customers of the significance of reductions in consumption of electricity during hours of peak demand.

20.11(1) *Annual notice.* Each electric utility shall provide its customers, on an annual basis, with a written notice explaining how growth in demand affects a utility's investment costs and why reduction of customer usage during periods of peak demand may help delay or reduce the amount of future rate increases. The notice shall be delivered to its customers between May 1 and June 15 of each year if peak demand is likely to occur during the months of June through September. If peak demand usually occurs during the months of October through February, the notice shall be delivered to its customers between August 1 and September 15.

20.11(2) *Notification plan.* Each investor-owned utility shall have on file with the board a plan to notify its customers of an approaching peak demand on the day when peak demand is likely to occur.

a. The plan shall include the following:

(1) A provision for a general notice to be given customers prior to the time when peak demand is likely to occur as prescribed in 20.11(2)*"b"* and an explanation of when and how notice of an approaching peak in electric demand will be given to customers.

(2) A provision for direct notice to be given customers whose load reduction will have a significant impact on the utility's peak. The utility shall provide for such notice to be given prior to the time when peak demand is likely to occur, as prescribed in 20.11(2)*"b,"* and shall explain the criteria used to identify customers to whom notice will be given and when and how notice will be given.

(3) A statement showing the total costs, with each component thereof itemized, projected to be associated with implementing the plan. Notice should be provided in the most efficient manner available. The board may reject a plan which includes excessive costs or which specifies an ineffective method of customer notification and may direct development of a new plan.

(4) The text of the general and direct message to be given in the general notice to customers. The message shall, at a minimum, include the name of the utility or utilities providing the notice, an explanation that conditions exist which indicate a peak in demand is approaching, and a statement that reduction in usage of electricity during the period of peak demand will ease the burden placed on the utility's system by growth in peak demand and may help delay or reduce the amount of future rate increases.

(5) A designation of the U.S. weather station(s), situated within the utility's service territory, whose temperature readings and predictions will be used by the utility in applying the standard in 20.11(2)*"b."*

(6) A provision for joint delivery, by two or more utilities, of the general notice to customers in regions of the state where U.S. weather station(s) predict conditions specified in 20.11(2)*"b"* will exist on the same day.

b. For purposes of this rule, peak demand is likely to occur on a nonholiday weekday between June 15 and September 15 when the following conditions exist:

(1) The utility's designated weather station predicts the temperature will rise above 95° Fahrenheit (35° Celsius), and the designated weather station officially recorded a temperature above 95° Fahrenheit (35° Celsius) on the previous day, or

(2) The utility's designated weather station predicts the temperature will rise to above 90° Fahrenheit (33° Celsius) on a day following at least two consecutive days of temperatures above 95° Fahrenheit (35° Celsius), as officially recorded by the designated weather station, but

(3) If a utility can demonstrate it would have been required to provide between June 15 and September 15 a peak alert notice to customers, because of the existence of the conditions set forth in 20.11(2)*"b"*(1) or 20.11(2)*"b"*(2), on more than six days in any one of the preceding ten years, the utility may substitute a 97° Fahrenheit (36° Celsius) standard in lieu of the 95° Fahrenheit (35° Celsius) standard in the subrule.

20.11(3) *Implementation of notification plan.* The utility shall implement the approved plan on each day of the year when peak demand is likely to occur, as prescribed by 20.11(2)*"b."*

20.11(4) *Permissive notices.* The standard for implementing peak alert notification in subrule 20.11(2) is a minimum standard and does not prohibit a utility or association of utilities from issuing a notice requesting customers to reduce usage at any other time.

20.11(5) *Annual report.* Each electric utility required by subrule 20.11(2) to file a plan for customer notification shall file, on or before April 1 of each year, a report stating the number of notices given its customers, the dates when notices were issued, the annual cost of providing both general and direct notice to customers and measures of kilowatt hour demand at the time when notice was given and at hourly intervals thereafter until kilowatt hour demand decreases to the level at which it was measured when the notice was issued. The annual report shall also include a statement of any problems experienced by the utility in providing customer notification of a peak demand and a proposal to modify the plan, if necessary, to make customer notification more effective. Modifications must be approved by the board before they are implemented.

199—20.12(476) New structure energy conservation standards. Rescinded IAB 11/12/03, effective 12/17/03.

199—20.13(476) Periodic electric energy supply and cost review [476.6(16)].

20.13(1) *Procurement plan.* The board shall periodically conduct a contested case proceeding for the purpose of evaluating the reasonableness and prudence of a rate-regulated public utility's electric fuel procurement and contracting practices. By January 31 each year the board will notify a rate-regulated utility if the utility will be required to file an electric fuel procurement plan. In the years in which it does not conduct a contested case proceeding, the board may require a utility to file certain information for the board's review. In years in which a full proceeding is conducted, a rate-regulated utility providing electric service in Iowa shall prepare and file with the board on or before May 15 of each required filing year a complete electric fuel procurement plan for an annual period commencing June 1 or, in the alternative, for the annual period used by the utility in preparing its own fuel procurement plan. A utility's procurement plan shall be organized to include information as follows:

a. *Index.* The plan shall include an index of all documents and information required to be filed in the plan, and the identification of the board files in which the documents incorporated by reference are located.

b. *Purchase contracts and arrangements.* A utility's procurement plan shall include detailed summaries of the following types of contracts and agreements executed since the last procurement review:

(1) All contracts and fuel supply arrangements for obtaining fuel for use by any unit in generation;

(2) All contracts and arrangements for transporting fuel from point of production to the site where placed in inventory, including any unit generating electricity for the utility;

(3) All contracts and arrangements for purchasing or selling allowances;

(4) Purchased power contracts or arrangements, including sale-of-capacity contracts, involving over 25 MW of capacity;

(5) Pool interchange agreements;

(6) Multiutility transmission line interchange agreements; and

(7) Interchange agreements between investor-owned utilities, generation and transmission cooperatives, or both, not required to be filed above, which were entered into or in effect since the last filing, and all such contracts or arrangements which will be entered into or exercised by the utility during the prospective 12-month period.

All procurement plans filed by a utility shall include all of the types of contracts and arrangements listed in subparagraphs (1) and (2) of this paragraph which will be entered into or exercised by the utility during the prospective 12-month period. In addition, the utility shall file an updated list of contracts that are or will become subject to renegotiation, extension, or termination within five years. The utility shall also update any price adjustment affecting any of the filed contracts or arrangements.

c. *Other contract offers*. The procurement plan shall include a list and description of those types of contracts and arrangements listed in paragraph 20.13(1)*"b"* offered to the utility since the last filing into which the utility did not enter. In addition, the procurement plan shall include a list of those types of contracts and arrangements listed in paragraph 20.13(1)*"b"* which were offered to the utility for the prospective 12-month period and into which the utility did not enter.

d. *Studies or investigation reports.* The procurement plans shall include all studies or investigation reports which have been considered by the utility in deciding whether to enter into any of those types of contracts or arrangements listed in paragraphs 20.13(1)*"b"* and *"c"* which will be exercised or entered into during the prospective 12-month period.

e. *Price hedge justification.* The procurement plan shall justify purchasing allowance futures contracts as a hedge against future price changes in the market rather than for speculation.

f. *Actual and projected costs.* The procurement plan shall include an accounting of the actual costs incurred in the purchase and transportation of fuel and the purchase of allowances for use in generating electricity associated with each contract or arrangement filed in accordance with paragraph 20.13(1)*"b"* for the previous 12-month period.

The procurement plan also shall include an accounting of all costs projected to be incurred by the utility in the purchase and transportation of fuel and the purchase of allowances for use in generating electricity associated with each contract or arrangement filed in accordance with paragraph 20.13(1)*"b"* in the prospective 12-month period.

If applicable, the reporting of transportation costs in the procurement plan shall include all known liabilities, including all unit train costs.

g. *Costs directly related to the purchase of fuel.* The utility shall provide a list and description of all other costs directly related to the purchase of fuels for use in generating electricity not required to be reported by paragraph *"f."*

h. *Compliance plans.* Each utility shall file its SO_2 compliance plan as submitted to the EPA. Revisions to the compliance plan shall be filed with each subsequent procurement plan.

i. *Evidence submitted.* Each utility shall submit all factual evidence and written argument in support of its evaluation of the reasonableness and prudence of the utility's procurement practice decisions in the manner described in its procurement plan. The utility shall file data sufficient to forecast fuel consumption at each generating unit or power plant for the prospective 12-month period. The board may require the submission of machine-readable data for selected computer codes or models.

j. *Additional information.* Each utility shall file additional information as ordered by the board.

20.13(2) *Periodic review proceeding.* The board shall periodically conduct a proceeding to evaluate the reasonableness and prudence of a rate-regulated utility's procurement practices. The prudence review of allowance transactions and accompanying compliance plans shall be determined on information available at the time the options or plans were developed.

a. On or before May 15 of a required filing year, each utility shall file prepared direct testimony and exhibits in support of its fuel procurement decisions and its fuel requirement forecast. This filing shall be in conjunction with the filing of the plans. The burden shall be on the utility to prove it is taking all reasonable actions to minimize its purchased fuel costs.

b. The board shall disallow any purchased fuel costs in excess of costs incurred under responsible and prudent policies and practices.

199—20.14(476) Flexible rates.

20.14(1) *Purpose.* This subrule is intended to allow electric utility companies to offer, at their option, incentive or discount rates to their customers.

20.14(2) *General criteria.*

a. Electric utility companies may offer discounts to individual customers, to selected groups of customers, or to an entire class of customers. However, discounted rates must be offered to all directly competing customers in the same service territory. Customers are direct competitors if they make the same end product (or offer the same service) for the same general group of customers. Customers that only produce component parts of the same end product are not directly competing customers.

b. In deciding whether to offer a specific discount, the utility shall evaluate the individual customer's, group's, or class's situation and perform a cost-benefit analysis before offering the discount.

c. Any discount offered should be such as to significantly affect the customer's or customers' decision to stay on the system or to increase consumption.

d. The consequences of offering the discount should be beneficial to all customers and to the utility. Other customers should not be at risk of loss as a result of these discounts; in addition, the offering of discounts shall in no way lead to subsidization of the discounted rates by other customers in the same or different classes.

20.14(3) *Tariff requirements.* If a company elects to offer flexible rates, the utility shall file for review and approval tariff sheets specifying the general conditions for offering discounted rates. The tariff sheets shall include, at a minimum, the following criteria:

a. The cost-benefit analysis must demonstrate that offering the discount will be more beneficial than not offering the discount.

b. The ceiling for all discounted rates shall be the approved rate on file for the customer's rate class.

c. The floor for the discount rate shall be equal the energy costs and customer costs of serving the specific customer.

d. No discount shall be offered for a period longer than five years, unless the board determines upon good cause shown that a longer period is warranted.

e. Discounts should not be offered if they will encourage deterioration in the load characteristics of the customer receiving the discount.

20.14(4) *Reporting requirements.* Each rate-regulated electric utility electing to offer flexible rates shall file annual reports with the board within 30 days of the end of each 12 months. Reports shall include the following information:

a. Section 1 of the report concerns discounts initiated in the last 12 months. For all discounts initiated in the last 12 months, the report shall include:

(1) The identity of the new customers (by account number, if necessary);

(2) The value of the discount offered;

(3) The cost-benefit analysis results;

(4) The end-use cost of alternate fuels or energy supplies available to the customer, if relevant;

(5) The energy and demand components by month of the amount of electricity sold to the customer in the preceding 12 months.

b. Section 2 of the report relates to overall program evaluation. Amount of electricity refers to both energy and demand components when the customer is billed for both elements. For all discounts currently being offered, the report shall include:

(1) The identity of each customer (by account number, if necessary);

(2) The amount of electricity sold in the last 12 months to each customer at discounted rates, by month;

(3) The amount of electricity sold to each customer in the same 12 months of the preceding year, by month;

(4) The dollar value of the discount in the last 12 months to each customer, by month; and

(5) The dollar value of sales to each customer for each of the previous 12 months.

c. Section 3 of the report concerns discounts denied or discounts terminated. For all customers specifically evaluated and denied or having a discount terminated in the last 12 months, the report shall include:

(1) Customer identification (by account number, if necessary);

(2) The amount of electricity sold in the last 12 months to each customer, by month;

(3) The amount of electricity sold to each customer in the same 12 months of the preceding year, by month; and

(4) The dollar value of sales to each customer for each of the past 12 months.

d. No monthly report is required if the utility had no customers receiving a discount during the relevant period and had no customers which were evaluated for the discount and rejected during the relevant period.

20.14(5) *Rate case treatment.* In a rate case, 50 percent of any identifiable increase in net revenues will be used to reduce rates for all customers; the remaining 50 percent of the identifiable increase in net revenues may be kept by the utility. If there is a decrease in revenues due to the discount, the utility's test year revenues will be adjusted to remove the effects of the discount by assuming that all sales were made at full tariffed rates for the customer class. Determining the actual amount will be a factual determination to be made in the rate case.

199—20.15(476) Customer contribution fund.

20.15(1) *Applicability and purpose.* This rule applies to each electric public utility, as defined in Iowa Code sections 476.1, 476.1A, and 476.1B. Each utility shall maintain a program plan to assist the utility's low-income customers with weatherization and to supplement assistance received under the federal low-income home energy assistance program for the payment of winter heating bills.

20.15(2) *Program plan.* Each utility shall have on file with the board a detailed description of its current program plan. At a minimum, the plan shall include the following information:

a. A list of the members of the governing board, council, or committee established to determine the appropriate distribution of the funds collected. The list shall include the organization each member represents;

b. A sample of the customer notification with a description of the method and frequency of its distribution;

c. A sample of the authorization form provided to customers;

d. The date of implementation.

Program plans for new customer contribution funds shall be rejected if not in compliance with this rule.

20.15(3) *Notification.* Each utility shall notify all customers of the fund at least twice a year. The method of notice which will ensure the most comprehensive notification to the utility's customers shall be employed. Upon commencement of service and at least once a year, the notice shall be mailed or personally delivered to all customers. The other required notice may be published in a local newspaper(s) of general circulation within the utility's service territory. A utility serving fewer than 6000 customers may publish their semiannual notices locally in a free newspaper, utility newsletter or shopper's guide instead of a newspaper. At a minimum the notice shall include:

a. A description of the availability and the purpose of the fund;

b. A customer authorization form. This form shall include a monthly billing option and any other methods of contribution.

20.15(4) *Methods of contribution.* The utility shall provide for contributions as monthly pledges, as well as one-time or periodic contributions. Each utility may allow persons or organizations to contribute matching funds.

20.15(5) *Annual report.* On or before September 30 of each year, each utility shall file with the board a report of all the customer contribution fund activity for the previous fiscal year beginning July 1 and ending June 30. The report shall be in a form provided by the board and shall contain an accounting of the total revenues collected and all distributions of the fund. The utility shall report all utility expenses directly related to the customer contribution fund.

20.15(6) *Binding effect.* A pledge by a customer or other party shall not be construed to be a binding contract between the utility and the pledgor. The pledge amount shall not be subject to delayed payment charges by the utility.

199—20.16(476) Exterior flood lighting. Rescinded IAB 11/12/03, effective 12/17/03.

199—20.17(476) Ratemaking treatment of emission allowances.

20.17(1) *Applicability and purpose.* This rule applies to all rate-regulated utilities providing electric service in Iowa. Under Title IV of the Clean Air Act Amendments of 1990, each electric utility is required to hold sufficient emission allowances to offset sulfur dioxide emissions at all affected and new units. The acquisition and disposition of emission allowances will be treated for ratemaking purposes as defined in this rule.

20.17(2) *Definitions.* The following words and terms, when used in this rule, shall have the meaning indicated below:

"Auction allowances" are allowances acquired or sold through EPA's annual allowance auction.

"Boot" means something acquired or forfeited to equalize a trade.

"Direct sale allowances" are allowances purchased from the EPA in its annual direct sale.

"Fair market value" is the amount at which an allowance could reasonably be sold in a transaction between a willing buyer and a willing seller other than in a forced or liquidation sale.

"Historical cost" is the amount of cash or its equivalent paid to acquire an asset.

"Original cost" is the historical cost of an asset to the person first devoting the asset to public service.

"Statutory allowances" are allowances allocated by the EPA at no cost to affected units under the Acid Rain Program either through annual allocations as a matter of statutory right and those for which a utility may qualify by using certain compliance options or effective use of conservation and renewables.

20.17(3) *Valuing allowances for ratemaking purposes.*

a. Statutory allowances. Valued at zero cost to electric utility.

b. Direct sale allowances. Valued at historical cost.

c. Auction allowances. Valued at historical cost.

d. Purchased allowances. Valued at historical cost.

20.17(4) *Valuing allowance inventory accounts.* Allowance inventory accounts shall be valued at the weighted average cost of all allowances eligible for use during that year.

20.17(5) *Valuing allowances acquired as part of a package.* Allowances acquired as part of a package with equipment, fuel, or electricity shall be valued at their fair market value at the time the allowances were acquired.

20.17(6) *Valuing allowances acquired through exchanges.*

a. *Exchanges without boot.* Electric utilities shall value allowances received in exchanges based on the recorded inventory value of the allowances relinquished.

b. *Exchanges with boot.* Electric utilities shall value allowances as the sum of the inventory cost of the allowances given up and the monetary consideration paid in boot for the newly acquired allowances. In determining the historical cost of allowances received, a gain (or loss) shall be recorded to the extent that the amount of boot received exceeds a proportionate share of the recorded weighted average inventory cost of the allowance surrendered. The proportionate share shall be based upon the ratio of the monetary consideration received (i.e., boot) to the total consideration received (monetary consideration plus the fair market value of the allowances received). The historical cost of the allowances received shall be equal to the amount derived by subtracting the difference between the boot received and the gain from the old inventory cost.

20.17(7) *Valuing allowances transferred among affiliates.*

a. Allowances transferred from a utility to a parent or unregulated subsidiary. Allowances shall be transferred at the higher of historical cost or fair market value.

b. Allowances transferred from an unregulated subsidiary or parent to a utility. Allowances shall be transferred at the lesser of original cost or fair market value.

c. Allowances transferred from a utility to an affiliated utility. Allowances shall be transferred at fair market value.

20.17(8) *Expense recognition and recovery of allowance costs.*

a. *Expense recognition.* Electric utilities shall charge allowances (including fractional amounts) to expense in the month in which related sulfur dioxide emissions occur.

b. *Expense recovery.* The expense associated with allowances used for compliance shall be passed through the energy adjustment as specified in rule 20.9(476).

c. *Allowance inventory shortage.* If a utility emits more sulfur dioxide in a month than it has allowances in inventory, the utility shall pass the estimated cost of acquiring the needed allowances through the energy adjustment. When the needed allowances are acquired, any difference between the estimated and actual cost of the allowances shall be passed through the energy adjustment as specified in rule 20.9(476).

20.17(9) *Gains/losses from allowance transactions.* The gains and losses from allowance transactions shall be passed through the energy adjustment as specified in rule 20.9(476).

20.17(10) *Allowance futures contracts.*

a. *Price hedging.* Electric utilities shall defer the costs or benefits from hedging transactions and include such amounts in inventory values when the related allowances are acquired, sold or otherwise disposed of. Where the costs or benefits of hedging transactions are not identifiable with specific allowances, the amounts shall be included in inventory values when the futures contract is closed.

b. *Speculation.* Allowance transactions entered into for the purpose of speculation shall not affect allowance inventory pricing.

20.17(11) *Working capital reserve of allowances.* A working capital reserve of allowances shall be established in each utility's rate case proceeding based on the probability of forced outages, fuel quality variability, variability in load growth, nuclear exposure, the price and availability of allowances on the national market, and any other factors that the board deems appropriate. The working capital reserve will earn at the utility's authorized rate of return.

20.17(12) *Allowances banked for future use.* Allowances banked for future use shall be considered plant held for future use in utility rate proceedings if a definitive plan and schedule for use of the allowances is deemed adequate by the board.

20.17(13) *Prudence of allowance transactions.* The prudence of allowance transactions shall be determined by the board in the periodic electric energy supply and cost review. The prudency review of allowance transactions and accompanying compliance plans shall be based on information available at the time the options or plans were developed. Costs recovered from ratepayers through the energy adjustment that are deemed imprudent by the board shall be refunded with interest to ratepayers through the energy adjustment as specified in rule 20.9(476).

199—20.18(476,478) Service reliability requirements for electric utilities.

20.18(1) *Applicability.* Rule 20.18(476,478) is applicable to investor-owned electric utilities and electric cooperative corporations and associations operating within the state of Iowa subject to Iowa Code chapter 476 and to the construction, operation, and maintenance of electric transmission lines by electric utilities as defined in subrule 20.18(4) to the extent provided in Iowa Code chapter 478.

20.18(2) *Purpose and scope.* Reliable electric service is of high importance to the health, safety, and welfare of the citizens of Iowa. The purpose of rule 20.18(476,478) is to establish requirements for assessing the reliability of the transmission and distribution systems and facilities that are under the board's jurisdiction. This rule establishes reporting requirements to provide consumers, the board, and electric utilities with methodology for monitoring reliability and ensuring quality of electric service within an electric utility's operating area. This rule provides definitions and requirements for maintenance of interruption data, retention of records, and report filing.

20.18(3) *General obligations.*

a. Each electric utility shall make reasonable efforts to avoid and prevent interruptions of service. However, when interruptions occur, service shall be reestablished within the shortest time practicable, consistent with safety.

b. The electric utility's electrical transmission and distribution facilities shall be designed, constructed, maintained, and electrically reinforced and supplemented as required to reliably perform the power delivery burden placed upon them in the storm and traffic hazard environment in which they are located.

c. Each electric utility shall carry on an effective preventive maintenance program and shall be capable of emergency repair work on a scale which its storm and traffic damage record indicates as appropriate to its scope of operations and to the physical condition of its transmission and distribution facilities.

d. In appraising the reliability of the electric utility's transmission and distribution system, the board will consider the condition of the physical property and the size, training, supervision, availability, equipment, and mobility of the maintenance forces, all as demonstrated in actual cases of storm and traffic damage to the facilities.

e. Each electric utility shall keep records of interruptions of service on its primary distribution system and shall make an analysis of the records for the purpose of determining steps to be taken to prevent recurrence of such interruptions.

f. Each electric utility shall make reasonable efforts to reduce the risk of future interruptions by taking into account the age, condition, design, and performance of transmission and distribution facilities and providing adequate investment in the maintenance, repair, replacement, and upgrade of facilities and equipment.

g. Any electric utility unable to comply with applicable provisions of rule 20.18(476,478) may file a waiver request pursuant to rule 199—1.3(17A,474,476,78GA,HF2206).

20.18(4) *Definitions.* Terms and formulas when used in rule 20.18(476,478) are defined as follows:

"Customer" means (1) any person, firm, association, or corporation, (2) any agency of the federal, state, or local government, or (3) any legal entity responsible by law for payment of the electric service from the electric utility which has a separately metered electrical service point for which a bill is rendered. Electrical service point means the point of connection between the electric utility's equipment and the customer's equipment. Each meter equals one customer. Retail customers are end-use customers who purchase and ultimately consume electricity.

"Customer average interruption duration index (CAIDI)" means the average interruption duration for those customers who experience interruptions during the year. It is calculated by dividing the annual sum of all customer interruption durations by the total number of customer interruptions.

$$\text{CAIDI} = \frac{\text{Sum of All Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}}$$

"Distribution system" means that part of the electric system owned or operated by an electric utility and designed to operate at a nominal voltage of 25,000 volts or less.

"Electric utility" means investor-owned electric utilities and electric cooperative corporations and associations owning, controlling, operating, or using transmission and distribution facilities and equipment subject to the board's jurisdiction.

"GIS" means a geospatial information system. This is an information management framework that allows the integration of various data and geospatial information.

"Interrupting device" means a device capable of being reclosed whose purpose is to interrupt faults and restore service or disconnect loads. These devices can be manual, automatic, or motor-operated. Examples may include transmission breakers, feeder breakers, line reclosers, motor-operated switches, fuses, or other devices.

"Interruption" means a loss of service to one or more customers or other facilities and is the result of one or more component outages. The types of interruption include momentary event, sustained, and scheduled. The following interruption causes shall not be included in the calculation of the reliability indices:

1. Interruptions intentionally initiated pursuant to the provisions of an interruptible service tariff or contract and affecting only those customers taking electric service under such tariff or contract;
2. Interruptions due to nonpayment of a bill;
3. Interruptions due to tampering with service equipment;
4. Interruptions due to denied access to service equipment located on the affected customer's private property;
5. Interruptions due to hazardous conditions located on the affected customer's private property;
6. Interruptions due to a request by the affected customer;
7. Interruptions due to a request by a law enforcement agency, fire department, other governmental agency responsible for public welfare, or any agency or authority responsible for bulk power system security;

8. Interruptions caused by the failure of a customer's equipment; the operation of a customer's equipment in a manner inconsistent with law, an approved tariff, rule, regulation, or an agreement between the customer and the electric utility; or the failure of a customer to take a required action that would have avoided the interruption, such as failing to notify the company of an increase in load when required to do so by a tariff or contract.

"Interruption duration" as used herein in regard to sustained outages means a period of time measured in one-minute increments that starts when an electric utility is notified or becomes aware of an interruption and ends when an electric utility restores electric service. Durations of less than five minutes shall not be reported in sustained outages.

"Interruption, momentary" means single operation of an interrupting device that results in a voltage of zero. For example, two breaker or recloser operations equals two momentary interruptions. A momentary interruption is one in which power is restored automatically.

"Interruption, momentary event" means an interruption of electric service to one or more customers of duration limited to the period required to restore service by an interrupting device. Note: Such switching operations must be completed in a specified time not to exceed five minutes. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or breaker operates two, three, or four times and then holds, the event shall be considered one momentary event interruption.

"Interruption, scheduled" means an interruption of electric power that results when a transmission or distribution component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventive maintenance, or repair. If it is possible to defer the interruption, the interruption is considered a scheduled interruption.

"Interruption, sustained" means any interruption not classified as a momentary event interruption. It is an interruption of electric service that is not automatically or instantaneously restored, with duration of greater than five minutes.

"Loss of service" means the loss of electrical power, a complete loss of voltage, to one or more customers. This does not include any of the power quality issues such as sags, swells, impulses, or harmonics. Also see definition of "interruption."

"Major event" will be declared whenever extensive physical damage to transmission and distribution facilities has occurred within an electric utility's operating area due to unusually severe and abnormal weather or event and:

1. Wind speed exceeds 90 mph for the affected area, or
2. One-half inch of ice is present and wind speed exceeds 40 mph for the affected area, or
3. Ten percent of the affected area total customer count is incurring a loss of service for a length of time to exceed five hours, or
4. 20,000 customers in a metropolitan area are incurring a loss of service for a length of time to exceed five hours.

"Meter" means, unless otherwise qualified, a device that measures and registers the integral of an electrical quantity with respect to time.

"Metropolitan area" means any community, or group of contiguous communities, with a population of 20,000 individuals or more.

"Momentary average interruption frequency index (MAIFI)" means the average number of momentary electric service interruptions for each customer during the year. It is calculated by dividing the total number of customer momentary interruptions by the total number of customers served.

$$\text{MAIFI} = \frac{\text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

"OMS" is a computerized outage management system.

"Operating area" means a geographical area defined by the electric utility that is a distinct area for administration, operation, or data collection with respect to the facilities serving, or the service provided within, the geographical area.

"Outage" means the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of service to customers, depending on system configuration.

"Power quality" means the characteristics of electric power received by the customer, with the exception of sustained interruptions and momentary event interruptions. Characteristics of electric power that detract from its quality include waveform irregularities and voltage variations, either prolonged or transient. Power quality problems shall include, but are not limited to, disturbances such as high or low voltage, voltage spikes and transients, flickers and voltage sags, surges and short-time overvoltages, as well as harmonics and noise.

"Rural circuit" means a circuit not defined as an urban circuit.

"System average interruption duration index (SAIDI)" means the average interruption duration per customer served during the year. It is calculated by dividing the sum of the customer interruption durations by the total number of customers served during the year.

$$\text{SAIDI} = \frac{\text{Sum of All Customer Interruption Durations}}{\text{Total Number of Customers Served}}$$

"System average interruption frequency index (SAIFI)" means the average number of interruptions per customer during the year. It is calculated by dividing the total annual number of customer interruptions by the total number of customers served during the year.

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

"Total number of customers served" means the total number of customers served on the last day of the reporting period.

"Urban circuit" means a circuit where both 75 percent or more of its customers and 75 percent or more of its primary circuit miles are located within a metropolitan area.

20.18(5) *Record-keeping requirements.*

**a. Required records for electric utilities with over 50,000 Iowa retail customers.*

(1) Each electric utility shall maintain a geospatial information system (GIS) and an outage management system (OMS) sufficient to determine a history of sustained electric service interruptions experienced by each customer. The OMS shall have the ability to access data for each customer in order to determine a history of electric service interruptions. Data shall be sortable by each of, and in any combination with, the following factors:

1. State jurisdiction;
2. Operating area (if any);
3. Substation;
4. Circuit;
5. Number of interruptions in reporting period; and
6. Number of hours of interruptions in reporting period.

(2) Records on interruptions shall be sufficient to determine the following:

1. Starting date and time the utility became aware of the interruption;
2. Duration of the interruption;
3. Date and time service was restored;
4. Number of customers affected;

*Error corrected IAC Supplement 1/22/03

5. Description of the cause of the interruption;
6. Operating areas affected;
7. Circuit number(s) of the distribution circuit(s) affected;
8. Service account number or other unique identifier of each customer affected;
9. Address of each affected customer location;
10. Weather conditions at time of interruption;
11. System component(s) involved (e.g., transmission line, substation, overhead primary main, underground primary main, transformer); and
12. Whether the interruption was planned or unplanned.

(3) Each electric utility shall maintain as much information as feasible on momentary interruptions.

(4) Each electric utility shall keep information on cause codes, weather codes, isolating device codes, and equipment failed codes.

1. The minimum interruption cause code set should include: animals, lightning, major event, scheduled, trees, overload, error, supply, equipment, other, unknown, and earthquake.
2. The minimum interruption weather code set should include: wind, lightning, heat, ice/snow, rain, clear day, and tornado/hurricane.
3. The minimum interruption isolating device set should include: breaker, recloser, fuse, sectionalizer, switch, and elbow.
4. The minimum interruption equipment failed code set should include: cable, transformer, conductor, splice, lightning arrester, switches, cross arm, pole, insulator, connector, other, and unknown.
5. Utilities may augment the code sets listed above to enhance tracking.

(5) An electric utility shall retain for seven years the records required by 20.18(5)*"a"*(1) through (4).

(6) Each electric utility shall record the date of installation of major facilities (poles, conductors, cable, and transformers) installed on or after April 1, 2003, and integrate that data into its GIS database.

b. Required records for all other electric utilities.

(1) Each electric utility, other than those providing only wholesale electric service, shall record and maintain sufficient records and reports that will enable it to calculate for the most recent seven-year period the average annual hours of interruption per customer due to causes in each of the following four major categories: power supplier, major storm, scheduled, and all other. Those electric utilities that provide only wholesale electric service shall provide their wholesale customers with the information necessary to allow those customers to ascertain the cause of power supply-related outages.

The category "scheduled" refers to interruptions resulting when a distribution transformer, line, or owned substation is deliberately taken out of service at a selected time for maintenance or other reasons.

The interruptions resulting from either scheduled or unscheduled outages on lines or substations owned by the power supplier are to be accounted for in the "power supplier" category.

The category "major storm" represents service interruptions from conditions that cause many concurrent outages because of snow, ice, or wind loads that exceed design assumptions for the lines.

The "all other" category includes outages primarily resulting from emergency conditions due to equipment breakdown, malfunction, or human error.

(2) When recording interruptions, each electric utility, other than those providing only wholesale electric service, shall use detailed standard codes for interruption analysis recommended by the United States Department of Agriculture, Rural Utilities Service (RUS) Bulletin 161-1, Tables 1 and 2, including the major cause categories of equipment or installation, age or deterioration, weather, birds or animals, member (or public), and unknown. The utility shall also include the subcategories recommended by RUS for each of these major cause categories.

(3) Each electric utility, other than those providing only wholesale electric service, shall also maintain and record data sufficient to enable it to compute systemwide calculated indices for SAIFI-, SAIDI-, and CAIDI-type measurements, once with the data associated with “major storms” and once without.

c. Each electric utility shall make its records of customer interruptions available to the board as needed.

20.18(6) *Notification requirements and other reporting.*

a. *Notification.* Each electric utility with over 50,000 Iowa retail customers shall notify the board of any major event as defined in subrule 20.18(4) and of any other widespread outage considered significant by the electric utility. The notice shall be provided as soon as practical once the occurrence of a major event becomes known to the electric utility. Notice shall be made by telephone to the board’s customer services section, by electronic mail to the board’s general E-mail address, or by facsimile. The notice shall include, to the electric utility’s best knowledge at the time:

(1) The nature or cause of the major event;

(2) The area affected by the major event;

(3) The number of customers that have experienced a sustained interruption of service; and

(4) The estimated time until service is restored.

The electric utility shall provide periodic updates to the board as new or improved information becomes available until all service is restored. The electric utility shall periodically report to the general public (via broadcasts or other media and by updating telephone answering machines) its best estimate as to when the service will be restored.

b. *Major event report.* Each electric utility with over 50,000 Iowa retail customers shall submit a report to the board within 20 business days after the end of a major event. The report shall include the following:

(1) A description of the event;

(2) The total number of customers out of service over the course of the major event at six-hour intervals, identified by operating area or circuit area;

(3) The longest customer interruption;

(4) The damage cost estimates to the electric utility’s facilities;

(5) The date and time when storm center opened and closed;

(6) The number of people used to restore service; and

(7) The name and telephone number of a utility employee who may be contacted about the outage.

20.18(7) *Annual reliability and service quality report for utilities with more than 50,000 Iowa retail customers.* Each electric utility with over 50,000 Iowa retail customers shall submit to the board and consumer advocate on or before May 1 of each year an annual reliability report for the previous calendar year for the Iowa jurisdiction. The report shall include the following information:

a. *Description of service area.* Urban and rural Iowa service territory customer count, Iowa operating area customer count, if applicable, and major communities served within each operating area.

b. *System reliability performance.*

(1) An overall assessment of the reliability performance, including the urban and rural SAIFI, SAIDI, and CAIDI reliability indices for the previous calendar year for the Iowa service territory and each defined Iowa operating area, if applicable. This assessment shall include outages at the substation, transmission, and generation levels of the system that directly result in sustained interruptions to customers on the distribution system. These indices shall be calculated twice, once with the data associated with major events and once without. This assessment should contain tabular and graphical presentations of the trend for each index as well as the trends of the major causes of interruptions.

(2) The urban and rural SAIFI, SAIDI, and CAIDI reliability average indices for the previous five calendar years for the Iowa service territory and each defined Iowa operating area, if applicable. The reliability average indices shall include outages at the substation, transmission, and generation levels of the system that directly result in sustained interruptions to customers on the distribution system. Calculation of the five-year average shall start with data from the year covered by the first Annual Reliability Report submittal so that by the fifth Annual Reliability Report submittal a complete five-year average shall be available. These indices shall be calculated twice, once with the data associated with major events and once without.

(3) The MAIFI reliability indices for the previous five calendar years for the Iowa service territory and each defined Iowa operating area for which momentary interruptions are tracked. The first annual report should specify which portions of the system are monitored for momentary interruptions, identify and describe the quality of data used, and update as needed in subsequent reports.

c. Reporting on customer outages.

(1) The reporting electric utility shall provide tables and graphical representations showing, in ascending order, the total number of customers that experienced set numbers of sustained interruptions during the year (i.e., the number of customers who experienced zero interruptions, the number of customers who experienced one interruption, two interruptions, three interruptions, and so on). The utility shall provide this for each of the following:

1. All Iowa customers, excluding major events.
2. All Iowa customers, including major events.

(2) The reporting electric utility shall provide tables and graphical representations showing, in ascending order, the total number of customers that experienced a set range of total annual sustained interruption duration during the year (i.e., the number of customers who experienced zero hours total duration, the number of customers who experienced greater than 0.0833 but less than 0.5 hour total duration, the number of customers who experienced greater than 0.5 but less than 1.0 hour total duration, and so on, reflecting half-hour increments of duration). The utility shall provide this for each of the following:

1. All Iowa customers, excluding major events.
2. All Iowa customers, including major events.

d. Major event summary. For each major event that occurred in the reporting period, the following information shall be provided:

(1) A description of the area(s) impacted by each major event;

(2) The total number of customers interrupted by each major event;

(3) The total number of customer-minutes interrupted by each major event; and

(4) Updated damage cost estimates to the electric utility's facilities.

e. Information on transmission and distribution facilities.

(1) Total circuit miles of electric distribution line in service at year's end, segregated by voltage level. Reasonable groupings of lines with similar voltage levels, such as but not limited to 12,000- and 13,000-volt three-phase facilities, are acceptable.

(2) Total circuit miles of electric transmission line in service at year's end, segregated by voltage level.

f. Plans and status report.

(1) A plan for service quality improvements, including costs, for the electric utility's transmission and distribution facilities that will ensure quality, safe, and reliable delivery of energy to customers.

1. The plan shall cover not less than the three years following the year in which the annual report was filed. A copy of the electric utility's documents and databases supporting capital investment and maintenance budget amounts required in 20.18(7)*"g"*(1) and 20.18(7)*"h"*(1), respectively, (including but not limited to transmission and distribution facilities, transmission and distribution control and communication facilities, and transmission and distribution planning, maintenance, and reliability-related computer hardware and software) shall be maintained in the utility's principal Iowa business location and shall be available for inspection by the board and office of consumer advocate. The utility's plan may reference said budget documents and databases, instead of duplicating or restating the detail therein. Copies of capital budgeting documents shall be maintained for five years.

2. The plan shall identify reliability challenges and may describe specific projects and projected costs. The filing of the plan shall not be considered as evidence of the prudence of the utility's reliability expenditures.

3. The plan shall provide an estimate of the timing for achievement of the plan's goals.

(2) A progress report on plan implementation. The report shall include identification of significant changes to the prior plan and the reasons for the changes.

g. Capital expenditure information. Reporting of capital expenditure information shall start with data from the year covered by the first Annual Reliability Report submittal so that by the fifth Annual Reliability Report submittal five years of data shall be available in each subsequent annual report.

(1) Each electric utility shall report on an annual basis the total of:

1. Capital investment in the electric utility's Iowa-based transmission and distribution infrastructure approved by its board of directors or other appropriate authority. If any amounts approved by the board of directors are designated for use in a recovery from a major event, those amounts shall be identified in addition to the total.

2. Capital investment expenditures in the electric utility's Iowa-based transmission and distribution infrastructure. If any expenditures were utilized in a recovery from a major event, those amounts shall be identified in addition to the total.

(2) Each electric utility shall report the same capital expenditure data from the past five years in the same fashion as in 20.18(7)*"g"*(1).

h. Maintenance. Reporting of maintenance information shall start with data from the year covered by the first Annual Reliability Report submittal so that by the fifth Annual Reliability Report submittal five years of data shall be available in each subsequent annual report.

(1) Total maintenance budgets and expenditures for distribution, and for transmission, for each operating area, if applicable, and for the electric utility's entire Iowa system for the past five years. If any maintenance budgets and expenditures are designated for use in a recovery from a major event, or were used in a recovery from a major event, respectively, those amounts shall be identified in addition to the totals.

(2) Tree trimming.

1. The budget and expenditures described in 20.18(7)*"h"*(1) shall be stated in such a way that the total annual tree trimming budget expenditures shall be identifiable for each operating area and for the electric utility's entire Iowa system for the past five years.

2. Total annual projected and actual miles of transmission line and of distribution line for which trees were trimmed for the reporting year for each operating area and for the electric utility's entire Iowa system for the reporting year, compared to the past five years. If the utility has utilized, or would prefer to utilize, an alternative method or methods of tracking physical tree trimming progress, it may propose the use of that method or methods to the board in a request for waiver.

3. In the event the utility's actual tree trimming performance, based on how the utility tracks its tree trimming as described in 20.18(7)*"h"*(2)"1," lags behind its planned trimming schedule by more than six months, the utility shall be required to file for the board's approval additional tree trimming status reports on a quarterly basis. Such reports shall describe the steps the utility will take to remediate its tree trimming performance and backlog. The additional quarterly reports shall continue until the utility's backlog has been reduced to zero.

20.18(8) *Annual report for all electric utilities not reporting pursuant to 20.18(7).*

a. By July 1, 2003, each electric utility shall adopt and have approved by its board of directors or other governing authority a reliability plan and shall file an informational copy of the plan with the board. The plan shall be updated not less than annually and shall describe the following:

(1) The utility's current reliability programs, including:

1. Tree trimming cycle, including descriptions and explanations of any changes to schedules and procedures reportable in accordance with 199 IAC 25.3(3)*"c"*;

2. Animal contact reduction programs, if applicable;

3. Lightning outage mitigation programs, if applicable; and

4. Other programs the electric utility may identify as reliability-related.

(2) Current ability to track and monitor interruptions.

(3) How the electric utility plans to communicate its plan with customers/consumer owners.

b. By April 1, 2004, and each April 1 thereafter, each electric utility shall prepare for its board of directors or other governing authority a reliability report. A copy of the annual report shall be filed with the board for informational purposes, shall be made publicly available in its entirety to customers/consumer owners, and shall report on at least the following:

(1) Measures of reliability for each of the five previous calendar years, including reliability indices if required in 20.18(5)*"b"*(3). These measures shall start with data from the year covered by the first Annual Reliability Report so that by the fifth Annual Reliability Report submittal reliability measures will be based upon five years of data.

(2) Progress on any reliability programs identified in its plan, but not less than the applicable programs listed in 20.18(8)*"a"*(1).

20.18(9) *Inquiries about electric service reliability.*

a. For electric utilities with over 50,000 Iowa retail customers. A customer may request a report from an electric utility about the service reliability of the circuit supplying the customer's own meter. Within 20 working days of receipt of the request, the electric utility shall supply the report to the customer at a reasonable cost. The report should identify which interruptions (number and durations) are due to major events.

b. Other utilities are encouraged to adopt similar responses to the extent it is administratively feasible.

These rules are intended to implement Iowa Code sections 17A.3, 364.23, 474.5, 476.1, 476.2, 476.6, 476.8, 476.20, 476.54, 476.66, 478.18, and 546.7.

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